Vermont Department of Public Service

Wholesale Electricity Market Price Forecast

DPS 2001

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Purpose of Report

The purpose of this report is to provide an updated projection of wholesale market prices likely to be seen in the New England energy market. This report builds on and uses a methodology similar to that used in previous DPS forecasts of wholesale prices.

This analysis was undertaken to reflect significant changes anticipated in the energy markets in New England. The most significant of these come from the reflection in futures prices of the large amount of new generation coming on line in New England and revised expectations of future gas prices which have changed markedly in the last year.

Methodology

The methodology used to develop these wholesale prices is similar to that used in previous forecasts by the DPS. A long term forecast was developed which assumes that new market entrants, building combined cycle natural gas plants, will be able to earn an assumed return on their investment through revenues from sales of the various market products traded in New England. Sales in the energy market are assumed to provide revenue to cover variable costs and, at times when the clearing price exceeds the variable cost, some contribution to fixed costs. The ancillary services markets and ICAP market are assumed to provide additional revenues to offset fixed costs. In an equilibrium market, the total revenues from all products sold in the market is assumed to be sufficient to cover all costs and produce an assumed return for the owner.

New England is currently in a period of excess supply. Given this surplus, competition will force prices down below that necessary to earn the assumed rate of return for some period of time. For those years where posted electricity futures prices are available, these provide a source for near term estimates of this discount. As the capacity surplus is reduced due to load growth and plant attrition, it is assumed average prices will rise to a level where a new entrant will find it attractive to enter the market. At this point, new entrants will enter the market and stabilize the price at approximately that level.

Results

The table below summarizes the annual average market prices for wholesale power supply, as well as a comparison to the most recent DPS price forecast. These prices can form the basis for computing retail power supply prices after adjustments for load factor, losses, risk and other factors.

Annual Average Wholesale Electric Prices	DPS 2001 Year 2000 Dollars	DPS 2001 Nominal Dollars	DPS 2000a Nominal Dollars
2002	$36.79	$38.84	$46.94
2003	$33.50	$36.34	$43.04
2004	$30.83	$34.36	$44.14
2005	$32.88	$37.66	$45.68
2006	$34.80	$40.95	$47.27
2007	$36.60	$44.25	$48.74
2008	$38.27	$47.55	$50.44
2009	$39.83	$50.85	$52.19
2010	$40.21	$52.74	$54.09
2011	$40.53	$54.62	$56.05
2012	$40.84	$56.56	$58.09
2013	$41.16	$58.57	$60.19
2014	$41.49	$60.66	$62.36
2015	$41.87	$62.90	$64.72
2016	$42.31	$65.31	$67.16
2017	$42.71	$67.73	$69.68
2018	$43.10	$70.24	$72.40
2019	$43.51	$72.86	$75.11
2020	$43.93	$75.57	$78.03

Fuel Prices

The Department contracted with Energy Ventures Associates ("EVA") to provide a long term price forecast for all fuels and sectors. This forecast was delivered in June 2001 and forms the basis of the fuel prices used in this projection. The forecast developed delivered prices for the utility sector, and specifically natural gas. It is assumed that a natural gas, combined cycle plant is the type of plant likely to be developed in the future and the plant whose costs will determine average marginal electricity prices into the future.

The short term market for gas has been unusually volatile in the last 12 months. While this forecast does not explicitly rely on the short term fuel price projections contained in the long term forecast, that volatility has undoubtably influenced short term futures prices for firm power which are used in this forecast. In the long term, forecasted prices assume that while new gas supplies will be more difficult and costly to extract, technological improvements in drilling and exploration techniques will serve to moderate real price increases. The following chart shows the forecasted prices for firm natural gas delivered to a power plant in southern New England.

DPS Natural Gas Price Forecast ($2000)										
	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	
$/MMBTU	$4.65	$4.05	$3.60	$3.39	$3.42	$3.46	$3.49	$3.53	$3.59	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
$/MMBTU	$3.63	$3.67	$3.72	$3.77	$3.82	$3.88	$3.94	$3.99	$4.05	$4.11

Other Inputs

New Capacity Additions

Developers have announced plans to build approximately 23,000 MW of new generation projects in New England, nearly all of which are fueled by natural gas. Even though New England experienced an all time peak load of over 24,000 MW in 2001, it is unlikely that all of these projects will be built. However, a significant number have progressed to the point where they are unlikely to be delayed and an online date can be predicted with some certainty. Approximately 5,300 MW of projects under construction are expected to come on line by the end of 2002, and another 1,600 MW will come on line by the end of 2004. The table below is a summary of projected annual capacity additions (summer rating) through the end of 2004.

Year	New Capacity (MW)	Cumulative Additions (MW)
1999	642	642
2000	1,279	1,921
2001	2,595	4,516
2002	5,339	9,855
2003	1,176	11,031
2004	488	11,519

Load Growth and Capacity Balance

The 2001 CELT report published by NEPOOL projects load growth to be 1.51% through 2010. This growth rate, coupled with the capacity additions shown above will result in a substantial capacity surplus throughout most of the decade. However, the CELT seems to be under reporting generation additions as shown above. The CELT also does not forecast generation retirements. However, it is unlikely that all existing units will continue to operate through the decade, and this forecast assumes that the capacity surplus will return to a reasonable level near the end of the decade.

Characteristics of New Generating Units

the following section discusses some of the other characteristics of new generating units which were used in the forecast.

Characteristics of New Units ($2000)						
	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (BTU/kWh)	Book Life (years)	Tax Life (years)
CC	600	25.00	1.02	7100	30	20
GT	370	3.50		10,000	25	15

Capital Costs

Estimates for capital costs remain unchanged from the DPS 2000 report. Overnight construction costs of $600/kW for a combined cycle plant and $370 for a simple cycle turbine are assumed. These were developed from various sources as detailed in the 2000 report. To these overnight costs were added AFUDC based on a 2 year construction cycle with modest exploratory investments occurring prior to that intensive period. These costs are stated in year 2000 dollars and are assumed to escalate at the inflation rate through the period of the analysis.

Capital Financing Rates

Financing for projects like these can be very complex, involving agreements between many lenders and equity holders. This analysis uses a simplified model of a capital structure which has a 50/50 debt to equity ratio, and assumes rates of 8.5% and 13% respectively for each component. This weighted average is used to calculate AFUDC amounts as well as ongoing capital financing requirements. These financing rates were based on a comprehensive survey done for the Vermont Department of Taxes titles "Valuation of Hydroelectric Generating Facilities on the Connecticut and Deerfield Rivers in Vermont". The report goes on to say that ". . .it would be unwise to take high estimates of required rates of return on common equity (ROE) at face value: sometimes a target rate of return is more like a "hoped for" rate than an "expected" rate, and it is the latter that represents the true cost of capital. Further, the winning bidder to acquire these assets might have unusually efficient financial arrangements."

General inflation was assumed to be 2.75%.

Heat Rate

An average heat rate of 7100 BTU/kWh was chosen as representative of best currently available technology for a combined cycle unit. While this heat rate is higher than some reported values, real operating conditions will increase heat rates over factory reported values for several reasons. Turbines often operate at conditions other than design conditions for much of their cycle. Over time, tolerances within turbine components erode, with a resultant effect on efficiency. Plant auxilaries and other parasitic load will reduce useful output of a plant. Finally, some time will be spent in warm up and partial load operation at less than full efficiency. Individually, these effects are not great, but cumulatively, they result in a measurable impact on heat rate.

Operating Costs

The model uses a fixed O&M value of $25.00 per kW-year and a variable O&M of $1.02/MWh.

Development of the Forecast Prices

All in prices for energy and ancillary products were developed using NatSource reports from September of 2001 which reported prices bid and ask out through 2004. Where off peak prices were not reported, a proxy was used based on the relationship between peak and off peak bids in prior years. Peak and off peak energy prices were averaged and combined on an hourly weighted basis to develop an annual average energy price. ICAP bids and asks were averaged in the same way. These were allocated to energy prices on a 100% capacity factor basis. These reported short term prices were used in the early years of the forecast. Based on anticipated timing of unit additions, 2004 was chosen as the year prices would turn around. A linear trajectory was used to escalate these values to full return in 2009.

No attempt was made to include any effects of Standard Market Design or Locational Marginal Pricing in this forecast.

Planned Enhancements

These forecast prices can form the basis of avoided costs to be used for DSM screening. Adjustments need to be made to allocate the costs to seasonal and peak periods, and to include some adjustment for the risks associated with portfolio management.